COMMENTS OF PSI ENERGY, INC. AND CINERGY CORP. CONCERNING THE INDIANA UTILITY REGULATORY COMMISSION'S ADVANCED NOTICE OF PROPOSED RULEMAKING <u>CONCERNING DISTRIBUTED GENERATION</u>

In response to the Indiana Utility Regulatory Commission's ("Commission") January 25, 2002 Advanced Notice Of Proposed Rulemaking ("ANOPR") concerning distributed generation ("DG"), PSI Energy, Inc. and Cinergy Corp. (collectively referred to as "PSI/Cinergy") submit these comments in support of the ANOPR. This initiative by the Commission is similar to/supports other DG initiatives by various other states, national governing bodies and technology developers. PSI/Cinergy believes that programs promoting DG should, if properly designed, accelerate the development and deployment of environmentally friendly power supply resources. PSI/Cinergy has been active in the development and implementation of DG and believes that appropriate use of DG can produce benefits for all stakeholders in Indiana. PSI/Cinergy looks forward to participating in the Commission's process of setting standards for the deployment of DG.

INTRODUCTION

In order to maintain a safe and reliable distribution system, PSI/Cinergy supports the development of minimum national interconnection standards for all DG projects. To effectively facilitate DG interconnection, the technical aspects of an interconnection standard must set on a national basis. PSI/Cinergy is actively participating in the development of the IEEE SCC21 P1547 interconnection standard. The Cincinnati Gas & Electric Company, the Cinergy Corp. operating utility in the State of Ohio, has been an active participant in the DG process facilitated by the Public Utilities Commission of Ohio.

It is imperative that any minimum interconnection standards for DG projects include appropriate provisions safeguarding the safety and health of employees of the electric systems that interconnect with DG projects. It is also imperative that any minimum interconnection standards for DG projects include appropriate provisions protecting the property and reliability of the interconnected electric system.

Siting and permitting of facilities are also crucial issues in the deployment of DG. Establishing pre-certification processes on emissions issues would help reduce the time and cost of siting smaller generating technologies. In addition, streamlining the other permitting requirements for small DG projects would also help reduce the costs of their installation.

PSI/Cinergy also supports the development of new DG technologies and applications. PSI/Cinergy has participated in demonstration of the world's first 250 kW PEM fuel cell, in siting and operation of microturbines at customer locations, and in testing of remote dispatching software. PSI/Cinergy has experience in monitoring and investigating new

DG for investment and pilot opportunities. PSI/Cinergy has also recently promoted photovoltaics to residential customers through a bill insert and information campaign.

Diversity in meeting system peaks has motivated PSI/Cinergy to develop innovative DG programs. PowerShare™, PSI/Cinergy's market-based pricing product, provides a "double duty" application for existing DG. On-site generating equipment can continue to provide the security of emergency backup power while reducing load during summer system peaks.

However, any program implemented to facilitate the development and deployment of DG must not be allowed to undermine the rights and responsibilities of Indiana electric utilities under IC 8-1-2.3. Similarly, any such program must be designed to observe applicable federal and state regulatory jurisdictional boundaries. Finally, the deployment of specific DG projects by customers may, depending upon how they are structured, raise issues concerning the possible "public utility" status of such customers.

ANSWERS TO SPECIFIC QUESTIONS IN THE ANOPR

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?

A DG facility is generally considered to be an electric generating facility of less than 10 MW. DG can be broadly defined as electric generating equipment that is:

- Located at a customer site and intended primarily to supply power to that customer; or
- Not associated with a customer site but still small enough to be interconnected at a distribution system level.

DG may operate in parallel with, or independent from, the utility transmission and distribution grid, and includes the following applications:

- Baseload or cogeneration operation;
- Reliability – emergency power and uninterrupted power system support (i.e., able to operate independent of the utility grid);
- Reliability and peak shaving – emergency and parallel operation (i.e., able to operate in parallel with the utility grid to shave peak or participate in utility peak shaving programs);

- Renewable, alternative fuel and "green" power applications: power generation from biomass, wind, solar and alternative energy (e.g., landfill gas, mine methane); and

- Operation completely isolated from the utility grid serving a single customer or group of customers.

The definition of DG varies more by application and location of installation rather than by the customer class of the installing customer. In other words, the specific application and installation location will primarily define the engineering characteristics and size of the DG project which may be interconnected with the electric system at that location.

b. Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?

The benefits of net metering to a customer are: (i) promotion of eligible technologies by providing a subsidy to the net metering customer from other customers; and (ii) a simple and inexpensive way to handle situations where it is difficult or inefficient, due to the type of generation and variation in the customer's load, to limit the DG generator output to a level at or below the customer's load.

The negative effect is that, because net metering involves a subsidy, it shifts some of the costs to serve net metering customers to other customers.

In order to reasonably restrict the amount of the potential subsidy, it is critical that any net metering program be properly designed and limited in scope.

c. What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?

Tariff structures that are primarily KWH based are most beneficial to the customer for net metering of DG.

PSI/Cinergy recognizes that in some cases net metering is a simple and efficient way to encourage and subsidize certain DG technologies. However, there are negative impacts as well. In light of this, PSI/Cinergy believes that any consideration of net metering should reflect the following:

- Net metering should be limited to only those energy forms that provide environmental benefits and that the customer cannot directly dispatch, such as solar and wind DG facilities. To fully utilize these available resources, the generation may at times exceed the customer's load and net metering provides a simple and inexpensive method to handle this situation.

- Net metering should be limited to a small generator (i.e., maximum 10 KW nameplate rating) for primarily residential or small commercial application.

- The size of the generator for any individual net metering application at a customer site should be limited to that which is intended to meet the customer's own load at that site.

- The generator covered by net metering must be located on the customer's premises.

- An aggregate utility system-wide limit should be placed on the total amount of DG installations on the utility's system that can qualify for net metering. Such a limit would prevent the net metering subsidy from being an undue burden on other ratepayers of the utility.

- An automatic rate adjustment mechanism or other method must be developed that allows the utility to currently collect the utility's otherwise un-recovered costs (because of the application of net metering) from the other ratepayers of the utility without the need for a general rate case or an extensive hearing process.

- The net metering should not result in a reduction of the utility's recovery of its transmission and distribution costs to serve the net metering location.

- The net metering customer should be required to execute a contract with the interconnected utility setting forth the applicable terms and conditions, including the minimum interconnection standards.

d. How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?

One of the advantages of net metering is the general use of simple inexpensive metering equipment. However, with simple inexpensive metering, it is impossible to determine the fixed amount of the utility's costs that are not being recovered for any individual net metering customer. More expensive load research metering with bi-directional load profiling capability may be used on sample sites (utilizing various technologies that qualify for net metering) to determine the average un-recovered cost per net metering installation. Additionally, any DG customer that is a net seller of electricity because the DG generates substantially more electricity than the customer's load can cause significant problems from an interconnection standpoint; accordingly, this type of DG installation should be avoided.

e. How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?

By definition, net metering is a means to avoid proper cost recovery from net metering customers of fixed and variable costs. This results in a subsidy to the net metering customer based upon the impact of the net metering. If proper recovery of fixed and variable costs is to be made from potential net metering customers, then other metering arrangements must be made such as is used with the DG buyback option in PSI/Cinergy's Peak Load Management rate rider (PowerShare).

f. How can stranded costs be identified and measured?

Stranded costs (i.e., a utility's un-recovered costs) in the DG context would generally be related to a utility's investment in facilities no longer used to serve the load for which they were installed because that load is being served by DG. Such facilities would primarily consist of facilities dedicated to serve one customer or a small group of customers. Once installed to serve one customer or a small group of customers, it is unlikely that such facilities would be useful to serve new load in other locations. The simplest measurement of such costs would be based upon the investments and other costs reflected in the utility's tariff. For example, transmission and distribution un-recovered costs (if net metering is allowed to reduce the utility's recovery of these costs) could be based upon the transmission and distribution investments and other costs reflected in the utility's tariff. A similar determination could be made for un-recovered generation costs.

Given the combination of PSI Energy Inc.'s low retail rates and the cost of DG technology, the economics do not currently look very favorable for wide-spread use of DG in PSI Energy, Inc.'s service territory. To the extent that the economics should change in the future, then this question would need to be revisited at that time.

g. What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?

It is highly unlikely that a DG project could produce material benefits to offset against a utility's otherwise un-recovered costs.

h. What rate design alternatives would reduce the potential for any stranded costs?

The initial starting point is that the utility's standard retail tariff should not encourage uneconomic bypass of the utility's system. Next, the utility should have a buyback rate for DG that encourages DG use only when it has value.

The simplest rate arrangement for DG would be a "buy-all/sell-all" arrangement where the utility pays the DG customer for the output of the DG and the customer purchases its full load requirements from the utility. The in-flow could be priced in accordance with the utility's existing retail tariff thus assuring no subsidization of the DG by other customers.

i. Should standby rates for backup power be used, and if so under what criteria?

Standby rates should be used to compensate the utility for providing to the DG customer any backup power, ancillary generation services, supplemental power, dedicated facilities, billing/metering and transmission and distribution delivery services. Criteria for the design of such rates should insure that all costs are recovered during the year to backup the customer at any time.

j. What different kinds of standby services do customers with DG require and can the utility reasonably supply?

DG customers may require backup power, ancillary generation services, supplemental power, dedicated facilities, billing/metering and transmission and distribution delivery services when the DG equipment is out of service for planned or unplanned outages. Such an outage could be scheduled or could occur instantly without notice, but in either case the customer would generally need the listed services. These services require available utility generating capacity and adequate transmission and distribution capacity. Generally, such capacity could be reasonably supplied with proper notice and planning and within reasonable limits. To the extent that additional capacity must be provided, rate mechanisms should be implemented to compensate the utility on a current basis for the costs of such capacity, including mechanisms to recover the costs of excess facilities.

k. In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.

At the source end of the distribution system are substations and feeders that serve the aggregate load of many existing customers on the system, as well as additional load from new customers. Annual peak load on these facilities is constantly changing as new load is added. As peak load reaches the capacity of these facilities, new capacity is added, typically in 10MVA or larger increments. Special arrangements must be made for large load additions.

At the point of connection with customer loads are facilities that serve either one customer or a group of customers. These facilities are designed to serve the projected peak load of the one customer or the group of customers. These facilities do not serve additional customers. Transformers, secondary lines, service drops, meters, tap lines, and primary backbone systems in subdivisions and commercial developments are examples of such facilities.

Capacity must be available in all of these facilities to provide backup power for a DG installation. Substations and feeders that serve aggregate loads could also serve aggregate DG installations. The capacity necessary to provide backup to all DG installations may not need to be the same as the sum total capacity of all DG installations if it is not probable that the DG installations would all need backup at the same time. The concept would work well if there are many small DG installations but not as well if there are only several DG installations and/or if they are relatively large DG installations. For example, if a distribution substation serves only one DG installation with a 500kW DG, then 500kW of backup capacity must be planned. Later on, if there are then 10 DG installations each with a 500kW DG, then the backup capacity could be well under the total amount of all 10 DG installations, or 5000kW, if it is very unlikely that more than one or two DG installations at once would need backup. However, an additional concern is that there may be a system event, such as a major voltage dip, that could result in the loss of all DG installations in the area. This would require the substation and feeder to backup all the DG installations at once, at least for a short time. Thus, it becomes very problematic to design a generic standby rate to cover the cost of providing backup for DG installations from substations and feeders. (See also, the portion of the response to question (j) above concerning a utility's current recovery of the costs of required additional capacity.)

Facilities that are at the point of connection must be designed with full backup capacity even if only used for backup infrequently. Thus, there is no reduction in cost of these distribution facilities due to a DG installation. Standby rates should recover any revenue loss due to the DG installation that is applicable to cost recovery of these facilities.

l. Are there areas in Indiana with distribution constraints?

Every year there are areas in the PSI Energy, Inc. service territory that have reached the capacity of the current distribution system. Typically, to relieve those constraints, new substations are added and feeder capacity is increased. One of the general characteristics of the PSI Energy, Inc. system and service territory is that there is not a significant range in cost to solve the constraint problems. The system does not have exceptionally long feeders, as is more common in very lightly populated areas of the U.S. or where widely separated pockets of load exist such as in mountainous areas. Most PSI Energy, Inc. projects consist of the addition or enhancement of a substation and/or the addition or upgrade of a mile or so of distribution feeder. Substation capacity is usually added in increments of 10MVA at a cost typically in the $50/kW range.

In urban areas with healthy growth, it is common to add one or more projects per year. In these areas, to delay a project one year by utilizing DG would require the same amount of

DG capacity or 10MVA. Relative to the transmission and distribution solution of $50/kW, DG would be in the $1000/kW range, or 20 times the cost.

In contrast to high growth areas where annual load growth in a small area may equal or exceed the smallest increment of substation capacity added, low load growth areas may have annual growth that is much less than the smallest increment of substation capacity used. Here, a small amount of DG could delay a 10MVA substation one year. Delay of a substation one year has a present worth value of approximately $35,000. If a 500kW DG could be used to do this, that transmission and distribution value would be worth a one time payment of $70/kW of DG capacity, still a long way from the DG cost of $1000/kW.

The conclusion that can be drawn from these numbers is that for DG to be a reasonable option, the transmission and distribution project cost must be many times the average cost and the amount of DG needed to delay a project must be very low.

m. Should utilities be required to file a location-specific set of T&D costs?

No, utilities should not be required to file a location-specific set of transmission and distribution costs . The issue related to DG is not geographic differences in embedded transmission and distribution costs, but differences in marginal cost to add capacity. PSI/Cinergy's experience is that there is not a significant variation within our service territory in this marginal cost. This does not rule out the possibility of a high marginal cost project; however, the occurrence will be rare. Additionally, technologies that make this practical are experimental and still under development. Research currently available includes a pilot program recently initiated in the State of New York designed to test whether DG could effectively substitute for distribution investment.

n. What constitutes an economically efficient buy-back rate?

Efficient DG buy-back rates and any resulting payments, directly or indirectly through net metering provisions, should reflect the following components:

- *Capacity Value* based on the DG's ability to contribute towards meeting a utility's planning and/or operating reserve criteria. The firmness and predictability of the DG at time of system peak demands are the key drivers in determining its capacity value.

- *Energy Value* based on the DG's ability to offset on-system generation or off-system purchases. Energy payments based on time differentiated avoided costs should be used to establish the energy value. This would require the installation of appropriate metering to measure the output of the generator.

- *Environmental Value* based on verifiable contributions towards meeting the utility's internalized environmental obligations (i.e., emission allowances under existing laws and regulations).

o. What information should be included in a utility standard application form for distributed generation?

All information necessary to evaluate the installation, including the name, location, in-service date, size and type of DG, single line diagram of the installation including protective relay functions, DG machine characteristics, anti-islanding scheme, transformer connections, and any pre-certification information.

p. What costs are incurred by a utility to review a DG project?

Costs consist of engineering time to review the proposed interconnection scheme and assess its ability to meet interconnection requirements. This may include system studies to determine any impact on the utility system in areas such as voltage regulation, overcurrent protection coordination, equipment ratings, overvoltage protection, etc.

q. Do these costs vary for different DG project proposals?

The costs may vary considerably. Engineering time may be less than one hour for a residential photovoltaic system utilizing an inverter that has been certified to meet UL1741. Engineering time could exceed one week for a multi-megawatt synchronous generator proposal that could have significant system impact.

r. How long should it take a utility to evaluate a project?

As stated in the response to question (q) above, the actual man-hours required to evaluate a project can range from one hour to over a week. Projects that utilize equipment that has been pre-tested to meet a standard and are small enough to have a negligible impact on the utility system can be evaluated quickly. Projects that are large, utilize a custom designed system, and/or that could have a significant impact on the utility system often take much longer. To efficiently utilize multiple resources and to account for the multiple projects being evaluated at any one time, the calendar time to evaluate a specific project may be increased. Additionally, larger projects often require several meetings and several iterations of information exchange between the project applicant and the utility to complete an evaluation.

s. What are the criteria a utility should use to evaluate a DG project?

The DG interconnection system must provide for safe and reliable parallel operation that will not negatively impact the safety, reliability, service quality, or operability of the utility's system. A partial list of issues that need to be addressed by detailed criteria include voltage regulation, grounding, transformer connections, overcurrent protection coordination, synchronization, disconnect devices, response to abnormal conditions, reconnection, harmonics, and flicker.

Environmental benefits from a DG project would also typically be considered in the evaluation of the project (e.g., biogas project).

Any supplemental power, backup, buyback and other service requirements of the DG project would also need to be known to evaluate the project.

Respectfully submitted,

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